NON-PUBLIC?: N
ACCESSION #: 9501250067

LICENSEE EVENT REPORT (LER)

FACILITY NAME: Diablo Canyon Unit 2 PAGE: 1 OF 8

DOCKET NUMBER: 05000323

TITLE: Manual Reactor Trip Due to Circulating Water Pump
Cavitation as a Result of Intake Screen Fouling
EVENT DATE: 12/19/94 LER #: 94-012-00 REPORT DATE: 01/18/95

OTHER FACILITIES INVOLVED: DOCKET NO: 05000

OPERATING MODE: 1 POWER LEVEL: 035

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR SECTION:
50.73(a)(2)(iv)

LICENSEE CONTACT FOR THIS LER:
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COMPONENT FAILURE DESCRIPTION:
CAUSE: SYSTEM: COMPONENT: MANUFACTURER:
REPORTABLE NPRDS:

SUPPLEMENTAL REPORT EXPECTED: NO

ABSTRACT:

On December 19, 1994, at 1014 PST, with Unit 2 in Mode 1 (Power Operation) at approximately 35 percent power, a manual Unit 2 trip was initiated due to circulating water pump cavitation due to intake screen fouling. The unit was stabilized in Mode 3 (Hot Standby) in accordance with plant emergency procedures. On December 19, 1994, at 1202 PST, a four-hour, non-emergency report was made to the NRC in accordance with 10 CFR 50.72(b)(2)(ii).

The event was due to the fouling of the intake circulating water screens during a period of high ocean swells that dislodged ocean plant life from the bottom.

An audible alarm was installed at the intake that activates if a traveling screen drive fails. Possible design and maintenance practice

enhancements will be investigated. An annunciator will be installed in the control room to alarm on high condenser differential pressure. Operation Procedure AP-7, "Partial Loss of Condenser Vacuum and Condenser Fouling," was revised to include guidance on condenser fouling. The operator rounds sheets were revised to provide guidance on monitoring performance of the intake screen wash system. A computer program was installed that enables control room operators to monitor and trend condenser differential pressures.

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END OF ABSTRACT



I. Plant Conditions

Unit 2 was in Mode 1 (Power Operation) at 35 percent power.

II. Description of Event

A. Summary

On December 19, 1994, at 1014 PST, with Unit 2 in Mode 1 (Power Operation) at approximately 35 percent power, a manual Unit 2 trip was initiated due to circulating water pump cavitation due to intake screen fouling. The unit was stabilized in Mode 3 (Hot Standby) in accordance with plant emergency procedures. A four-hour, non-emergency report was made to the NRC at 1202 PST in accordance with 10 CFR 50.72(b)(2)(ii).

B. Background

The circulating water system provides a continuous saltwater supply to the main condenser (KE), condensate cooler (KE)(HX), service water cooling system (BI), and intake cooling system (KE). The saltwater enters the cooling water intake structure by passing through bar racks and then through traveling screen assemblies. Each unit has two, single-stage, circulating water pumps (CWP) and each CWP has three traveling screens (KE)(SCN). CWP 2-1 is protected by traveling screens 2-1, 2-2, and 2-3. CWP 2-2 is protected by traveling screens 2-4, 2-5, and 2-6. The bar racks and traveling screens prevent floating debris and sea life from entering the system and restricting flow through the main condenser.

C. Event Description

On December 19, 1994, at 0600 PST, the speed of all circulating water traveling screens was being controlled manually due to high seas. At 0630 PST, the control room operators noticed condenser differential pressure Increasing. Operators began to make plans to clean the Unit 2 condenser. At 0700 PST, the intake operator discovered that the intake screen 2-5 was heavily loaded and large amounts of debris were being carried over to the other screens resulting in condenser tubesheet (KE)(HX) blockage. The operator attempted to correct this condition by increasing the spray wash flow to the heavily loaded traveling screens. Subsequently, the intake operator discovered that intake screens 2-2 and 2-4 had stopped running. The 2-2 and 2-4 screens were restarted in high speed. At 0829 PST, due to increasing differential pressure, Unit 2 commenced ramping to 50 percent power to clean



the condenser. At 0905 PST, the Unit 2 ramp rate was increased when condenser differential pressure continued to increase. During the ramp, screen 2-1 became torn and began passing debris. The intake gate (KE)(GATE) in front of traveling screen 2-1 was closed to prevent further debris from passing through the damaged screen. At 1001 PST, CWP 2-2 was shut down to clean the waterbox due to a high condenser differential pressure. After CWP 2-2 was secured, debris collected on the CWP 2-2 traveling screens, floated loose and collected on screens 2-2, and 2-3. As a result of the heavy loading, the shear pins on screens 2-2 and 2-3 sheared. With the traveling screens stopped, the debris loading rapidly increased, restricting flow to CWP 2-1. At 1014 PST, CWP 2-1 electrical current readings indicated that the pump was cavitating. At 1014 PST, at approximately 35 percent power, a manual Unit 2 trip was initiated and CWP 2-1 was secured. The unit was stabilized in Mode 3 in accordance with plant emergency procedures.

Due to the loss of the CWPs, the operator closed the MSIVs (SB)(LOV) and broke condenser vacuum. After the MSIVs were closed, operators observed that two of the 10 percent steam dump valves (SB)(PCV) (PCV 19 and 22) were not properly controlling pressure allowing the pressure to increase to 20 and 25 psi, respectively, above the setpoint of 1035 psi. PCV

19 and 22 operated and exhibited a chugging action. Main steam safety valve (MSSV) 2-RV-3 lifted twice and 2-RV-58 lifted once. Both relief valves seated properly. Operations personnel adjusted the valve controller to reduce steam generator pressure.

Shortly after the trip, control room operators observed low reactor coolant pump (AB)(P)(RCP) seal injection flow. Several charging flow pump configurations were attempted that were not successful in restoring normal RCP seal flow. At 1204 PST, RCP seal injection needle valves (CB)(INV) were throttled open and RCP seal injection flow was restored to the normal range.

On December 19, 1994, at 1202 PST, a four-hour, non-emergency report was made to the NRC in accordance with 10 CFR 50.72(b)(2)(ii).

D. Inoperable Structures, Components, or Systems that Contributed to the Event

During the heavily fouled condition prior to the event, the intake operator identified insufficient screen spray flow to intake screen 2-5. A plant problem report was initiated to investigate the root cause and to determine corrective action to prevent recurrence.

E. Dates and Approximate Times for Major Occurrences



1. December 19, 1994, 0829 PST: Unit 2 ramp down initiated.

2. December 19,1994,1014 PST: Event/Discovery Date: Manual unit trip initiated.

3. December 19, 1994, 1202 PST: A four-hour, non-emergency report was made to the NRC in accordance with 10 CFR 50.72(b)(2)(ii).

F. Other Systems or Secondary Functions Affected

1. Following the reactor trip, the RCP seal injection was lower than normal. An investigation into the low flow

condition could not conclusively determine the cause. Seal injection filter 2-2 was removed and found to be damaged. PG&E believes that the most probable cause of the low flow condition was an increase in the seal injection filter (CB)(FLT) differential pressure following the reactor trip. This condition resulted in a disturbance of the piping and contained fluid that dislodged particulates lodged in the piping system and deposited them at the throttle valve inlet, possibly along the RCP shaft, and at the #1 seal causing a reduction in flow to the RCP seals. Opening the seal injection needle valves and establishing normal seal flow rates cleared the particulates from the affected seal injection flow paths. A plant problem report was initiated to investigate the root cause and to determine corrective action to prevent recurrence.

2. Following the reactor trip, operators observed that two of the 10 percent steam dump valves (PCV 19 and 22) were not properly controlling pressure and allowing the pressure to increase 25 psi above the setpoint. Operations personnel adjusted the valve controller setpoint to reduce steam generator pressure. An investigation determined the PCV 19 and 22 control modules were out of tolerance. The

control module for PCV-19 was adjusted to within tolerance and returned to service. The controller for PCV-22 was replaced. A plant problem report was initiated to investigate the root cause and to determine corrective action to prevent recurrence.

3. Following the reactor trip, MSSV 2-RV-3 lifted twice and 2-RV-58 lifted once. The openings were caused by a combination of high steam pressure at the MSSV and cyclic hydraulic forces below the MSSV and vibration due to chugging of the 10 percent atmospheric steam dump valves. A plant problem report was initiated to investigate the root cause and to determine corrective action to prevent recurrence.



G. Method of Discovery

The event was immediately apparent to plant operators due to alarms and indications received in the control room.

H. Operator Actions

Licensed plant operators in the control room responded in accordance with established emergency procedures, confirmed the reactor trip, verified proper engineered safety feature actuations, and initiated manual actions to stabilize the unit in Mode 3.

Approximately 5 minutes after the trip, plant operators manually closed the MSIVs due to the loss of condenser cooling. The MSIVs were subsequently reopened.

I. Safety System Responses

1. The reactor trip breakers (JC)(BKR) opened.

2. The main turbine tripped.

3. The control rod drive mechanism (AA)(DRIV) allowed the control rods to drop into the core.

4. Four 10 percent steam relief valves opened to relieve pressure.

5. Main steam safety valves 2-RV-3 and 2-RV-58 lifted and reseated.

6. Auxiliary feedwater was initiated.

III. Cause of the Event

A. Immediate Cause

The immediate cause of the manual reactor trip was anticipated loss of vacuum and subsequent turbine trip which would result from condenser tubesheet plugging or securing the only remaining CWP. The CWP was secured to prevent further traveling screen and pump damage.

B. Root Cause

The root cause for the manual reactor trip was a high ocean swell condition that dislodged ocean plant life and caused the intake traveling screens to foul with kelp.

C. Contributory Cause

1. Inadequate wash spray to intake traveling screen 2-5 prior to event.

2. The screen management program did not prevent rapid condenser fouling. The screen management program includes design, maintenance, and operation of the intake traveling screens.

IV. Analysis of the Event

A manual reactor trip from 50 percent power is a previously analyzed FSAR Update, Chapter 15, Condition 11 event. The ten percent steam dump valves, the MSSVs, and the pressurizer controlled reactor coolant temperature and pressure in accordance with plant design basis. Therefore, the health and safety of the public were not adversely affected by this event.

V. Corrective Actions

A. Immediate Corrective Actions

1. All damaged baskets on the traveling intake screens were repaired.

2. The operations department issued a shift order covering the following:

a. Operators will be continuously stationed at the intake until high sea conditions have abated.

b. The intake traveling screens will be operated in the continuous manual mode until high seas have abated.

c. An operator will periodically monitor the traveling screens spray nozzles to assure adequate flow.

d. Control room operators will continue to monitor the computer display of condenser differential pressure

during periods of high seas.

3. The shear pins on the affected traveling screens were replaced.



B. Corrective Actions to Prevent Recurrence

1. The failure of traveling screens 2-2 and 2-4 is under investigation. As an interim measure, an audible alarm at the intake was installed. The alarm is activated if a traveling screen drive fails. Upon determination of the cause(s) for failure, corrective action will be taken to prevent recurrence.

2. PG&E will investigate and implement possible intake design, operation, and maintenance practice enhancements.

3. An annunciator will be installed in the control room to alarm on high condenser differential pressure.

4. Operation Procedure AP-7, "Partial Loss of Condenser Vacuum and Condenser Fouling," was revised to include guidance on condenser fouling. The guidance includes when to start a Unit ramp, strategy to use for condenser fouling, and additional guidance on when to Initiate a manual unit trip.

5. The operator rounds sheets have been revised to provide guidance on the following:

a. Intake operators shall periodically perform various checks on the intake traveling screen performance.

b. Intake operators shall periodically ensure that the traveling screens have adequate spray flow and the intake debris troughs are clean.

6. A computer program enabling control room operators to monitor and trend condenser differential pressures has been installed.

VI. Additional Information

A. Failed Components

None.

B. Previous LERs on Similar Problems

LER 2-85-018-01, "Manual Reactor Trip Prompted by Failure of Digital Rod Position Indication System Followed by Spurious Safety Injection."

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On December 2, 1985, control room operators were reducing Unit 2 power preparatory to separating from the PG&E transmission system because of kelp buildup and fouling of the circulating water system at the ocean intake structure. During preparations, the digital rod position indication (DRPI) system experienced a data "A" failure and general warning on each control rod caused by a power supply failure. The control operator manually initiated a unit trip. An investigation revealed a faulty DC logic power supply, resulting in the data "A" failure and general warning on every control rod. The DRPI power supply was repaired and the system returned to service. The root cause of the manual reactor trip was the failure of the DRPI. Therefore, the corrective actions taken for LER 2-85-018-01 would not have prevented this event.



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January 18, 1995

PG&E Letter DCL-95-011

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555

Docket No. 50-323, OL-DPR-82
Diablo Canyon Unit 2
Licensee Event Report 2-94-012-00
Manual Reactor Trip Due to Circulating Water Pump Cavitation
as a Result of Intake Screen Fouling

Gentlemen:

Pursuant to 10 CFR 50.73(b)(2)(ii), PG&E is submitting the enclosed Licensee Event Report concerning a manual reactor trip due to circulating water pump cavitation caused by fouling of the intake water traveling screens.

This event did not adversely affect the health and safety of the public.

Sincerely,

Gregory M. Rueger

cc: Edward T. Baker
L. J. Callan
Kenneth E. Perkins
Michael D. Tschiltz
Diablo Distribution
INPO

Enclosure

DC2-94-OP-N062

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